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April 6, 2006

Implementation of the Alternative Energy Portfolio Standards Act of 2004 — Docket No. M-00051865

Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant to 66 Pa. C.S. § 2807(e)(2) — Docket No. L-00040169

Reply Comments of DTE Energy Co.

DTE Energy Co. (**DTE**) is pleased to provide reply comments as permitted by the request of the Public Utility Commission (the **Commission**) dated February 8, 2006 in the above captioned dockets for responses to certain questions.

DTE, as previously described, is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. In particular, DTE subsidiaries are developing coal mine methane and landfill gas projects in the PJM service territory that would be eligible to sell renewable energy certificates (**RECs**) under the Alternative Energy Portfolio Standards Act of 2004 (the **Alternative Energy Act**).

Among the many responses the Commission received to its request for comments only a handful were opposed to permitting default providers to use long term contracts to acquire electric energy. Each of those commenters is an independent electric generation supplier, and, while their comments are full of pious phrases about protecting retail competition, their principal concern appears to be to avoid any possibility that default service prices might be competitive with their own offerings.

Two of these commenters, Strategic Energy L.L.C. and Reliant Energy, Inc., specifically cited to Texas' experience with its renewable portfolio standard as evidence that long term contracts are unnecessary. This a substantial misreading of the Texas experience.

Neither the Texas legislature in adopting its renewable portfolio standard, nor the Texas Public Utility Commission in implementing it, either required or prohibited Texas distribution companies entering into long-term contracts to fulfill their obligation for renewable energy. However, those companies have chosen to do so. Texas' renewable energy requirement has been overwhelmingly met with wind power, and the wind power projects have been developed and financed with long-term contracts.

Attached as Exhibit 1 is an assessment of the Texas RPS experience prepared by the Berkley National Laboratory. Section 3.3 of that report states:

> An equally important achievement under the Texas RPS is that obligated electricity suppliers have been willing to sign long-term (10-25 year) contracts for RECs and the associated electricity. Without long-term contracts, renewable energy developers are faced with the unenviable position of developing merchant renewable energy projects with highly uncertain returns (Citations omitted). Similarly, electricity retailers risk not being able to procure the requisite number of RECs by year's end or only being able to procure credits at astronomical prices due to supply constraints or market manipulation.
>
> Long-term contracts, on the other hand, ensure developers a stable revenue stream and access to low-cost financing, while delivering

to electricity retailers a reliable stream of renewable electricity at stable prices. In fact, though renewable developers are often able to choose between REC-only sales and sales that combine the RECs and electricity, virtually all contracts to date have covered both the certificates and the electricity. This clearly demonstrates the importance of reducing revenue-risk on the part of the developers.

While this report was prepared in 2001, it accurately represents the ongoing experience in Texas. Attached as Exhibit 2 is an affidavit from Craig Matacyznski, President of Renewable Energy Systems Americas, Inc. (**RES-Americas**), the United States arm of one of the largest wind power developers worldwide and a leading developer of wind projects in Texas. As the affidavit makes clear, all of RES-Amercas' projects in Texas have been developed and financed with long-term contracts. Moreover, the affidavit states:

> Because RES Americas constructs wind farms in addition to developing such facilities, we do business with many of the entities developing wind facilities in Texas and elsewhere in the United States. It is our understanding that most of the wind developers in Texas have entered into or are striving to enter into long term PPAs [power purchase agreements] for the output of their wind farms.... Long term contracts are an important part of any renewable market structure because they mitigate the price uncertainty and risk associated with developing renewable projects, ultimately driving down the costs to developers and consumers and encouraging development.

The apparently universal use of long-term contracts for renewable resources has not adversely affected Texas retail competition. Over 70 percent of large non-residential customers and over 25 percent of all other customers are no longer served by their original distribution company.[*]

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[*] The Status of Retail Electric Competition in Texas: Are We There Yet? Evan Evans, C.H. Guernsey & Company at p.11; available at www.chquernsey.com/press/Articles/August%202005%20 status%20of%20Retail%20choice-TEC%20mtg.pdf.

The Texas experience is not an anomaly. The benefit of long-term contracts for the health of short-term markets is becoming widely accepted among economists working on the design of electricity markets. Attached as Exhibit 3 with the authors' permission is an article by Peter Cramton and Steven Stoft that will appear soon in the *Electricity Journal*. As their attached biographical material makes clear, Professor Cramton has been a principal architect of market designs for ISO-New England while Professor Stoft has played a similar role in PJM. They conclude that long-term contracts are a necessary tool for consumer protection in electricity markets.

If the Commission has any questions or would like clarification of any of the foregoing, please do not hesitate to contact the undersigned.

Respectfully submitted,

C. Baird Brown
Ballard Spahr Andrews & Ingersoll, LLP
on behalf of DTE Energy Co.

EXHIBIT 1

LBNL-49107

ERNEST ORLANDO LAWRENCE
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The Renewables Portfolio Standard in Texas: An Early Assessment

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November 2001

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Power Technologies of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Disclaimer

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Abstract

Texas has rapidly emerged as one of the leading wind power markets in the United States. This development can be largely traced to a well-designed and carefully implemented renewables portfolio standard (RPS). The RPS is a new policy mechanism that has received increasing attention as an attractive approach to support renewable power generation. Though replacing existing renewable energy policies with an as-of-yet largely untested approach in the RPS is risky, early experience from Texas suggests that an RPS can effectively spur renewables development and encourage competition among renewable energy producers. Initial RPS targets in Texas will be far exceeded by the end of 2001, with as much as 930 MW of wind slated for installation this year. RPS compliance costs appear negligible, with new wind projects reportedly contracted for under 3(US)¢/kWh, in part as a result of a 1.7(US)¢/kWh production tax credit, an outstanding wind resource, and an RPS that is sizable enough to drive project economies of scale. Obliged retail suppliers have been willing to enter into long-term contracts with renewable generators, reducing important risks for both the developer and the retail supplier. Finally, the country's first comprehensive renewable energy certificate program has been put into place to monitor and track RPS compliance.

Acknowledgments

Work reported here was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Power Technologies of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098, and by the German Aerospace Center. We particularly thank Jack Cadogan and Larry Mansueti of the U.S. Department of Energy for their support of this work. For providing useful information or helpful review comments, we also thank Mark Bolinger (Berkeley Lab), Mark Kapner (Austin Energy), Reid Buckley (Orion Energy LLC), Nicole Fabri (Natsource LLC), David Hurlbut (Texas PUC), Brian Evans (RES Inc.), Henry Eby (LCRA), Russel Smith (TREIA), Steve Palomo (U.S. DOE), Cathy Ghandehari (U.S. DOE), Doug Seiter (U.S. DOE), Mark MacLeod (Environmental Defense), Lars Nilsson (IMES), Peter Helby (IMES), and Lori Bird (National Renewable Energy Laboratory).

1. Introduction

The renewables portfolio standard – a policy instrument that ensures that a minimum amount of renewable energy is included in the portfolio of electricity resources – has become increasingly popular in energy policy and research circles worldwide. The concept of an RPS is deceptively simple: it is a requirement for retail electricity suppliers (or, alternatively, electricity generators or consumers) to source a minimum percentage of their electricity needs from eligible renewable resources. To add flexibility and reduce the cost of meeting the requirement, tradable renewable energy certificates (REC) can be used to track and verify compliance.

The RPS has been recognized by some as perhaps the ideal way to encourage renewable energy development in competitive markets: the RPS aims to ensure that renewable energy targets are met at least cost and with a minimum of ongoing administrative involvement by the government (Rader and Norgaard 1996, Haddad and Jefferiss 1999, Berry and Jaccard 2001, Morthorst 2000). Detailed recommendations for the proper design of an RPS have been provided (Rader and Hempling 2001, Timpe et al. 2001, Mitchell and Anderson 2000, Price Waterhouse Coopers 1999, Schaeffer et al. 2000, Wiser and Hamrin 2000, Schaeffer and Sonnemans 2000, Espey 2001). Others have sought to project the costs and impacts of RPS requirements (e.g., Clemmer et al. 1999). Most of these recommendations and cost estimates have had to rely on theoretical principles, however, as practical experience in the application of the RPS has been limited. RPS policies have been established by legislation in 10 U.S. states, and in the countries of Australia, Austria, Belgium, Italy, and the United Kingdom, but experience is only beginning to be gained with the actual operation of the policy.[1]

Replacing existing renewable energy policies with a largely as-of-yet untested approach in the RPS is risky business. Some countries – including Germany, Spain, and Denmark – have had particularly good success in driving clean energy development with attractive "feed-in" tariffs. And limited experience in several U.S. states already shows that a poorly designed RPS will do little to increase renewable generation (Rader 2000). Nonetheless, emerging experience from the state of Texas demonstrates that a well-crafted and implemented RPS can deliver on its promise of strong and cost-effective support for renewable energy. While experience even in Texas is limited, the Texas RPS has already fostered substantial renewable energy development, surpassing the achievements of any other RPS developed to date. This paper describes the design of the Texas RPS and offers an early assessment.

2. The Anatomy of the Texas RPS

In 1999, the Texas government – under then governor George W. Bush – established an RPS within the restructuring of the state's electricity market.[2] Detailed RPS regulations were subsequently established by the Texas Public Utilities Commission.[3] The RPS is intended to encourage the development of new, environmentally beneficial resources and thereby reduce the

[1] Denmark and Sweden have also both announced plans to move towards an RPS, though those plans are not finalized in formal legislation. The Netherlands is credited for being the first to develop a REC trading program (in 1998), but that program has not yet been used to meet mandatory renewable energy obligations under an RPS.
[2] § 39.904 of the Public Utility Regulatory Act (PURA).
[3] PUC Substantive Rules §25.173 Related to Goal for Renewable Energy.

environmental impacts of power production, and contribute to the development of rural areas by creating new renewable energy business opportunities. Resistance towards the RPS was significant among some sectors, especially large industrial customers. Helping to overcome this resistance was the fact that the RPS was only a small part of the overall restructuring legislation in which it was embedded, that the renewable and environmental advocacy communities argued forcefully and collaboratively for the RPS, and that public surveys showed overwhelming support for renewable energy.

The Texas RPS requires the installation of 2000 MW of new renewable capacity by the year 2009, in addition to preserving the 880 MW of renewable energy already on line.[4] This translates to about 3% of present electricity consumption.[5] This goal is modest relative to the enormous potential for renewable energy development in Texas and what it would take to create a truly "sustainable" electricity supply.[6] Nonetheless, it represents a marked increase in renewable energy capacity in the state, and represents one of the most ambitious contemporary state renewable energy policies in the U.S. in terms of capacity additions.

Texas Details and RPS Timeline

STATE POPULATION
20 million (1999)

ANNUAL RETAIL ELECTRICITY SALES
305 million MWh (1998)

FUEL MIX
39% coal, 49% natural gas, 11% nuclear, 1% renewable

TIMELINE

RPS Legislation	May 1999
RPS Rulemaking Begins	June 1999
RPS Rulemaking Ends	December 1999
REC System Established	July 2001
RPS Begins	January 2002
RPS Ends	January 2020

Intermediate new renewable capacity goals in Texas are 400 MW by 2003, 850 MW by 2005, 1400 MW by 2007, and finally 2000 MW by 2009 and through 2019. These capacity goals are translated into megawatt-hour based energy requirements by using an average capacity factor of all eligible renewable plants; its value is initially set at 35% and will be adjusted over time based on actual plant performance.

Electricity retailers that serve markets open to competition are obliged to fulfill their portion (based on yearly retail electricity sales) of the renewable energy requirement by presenting RECs to the regulating authority on an annual basis. The obligation begins in 2002 and ends in 2019. The tradable RECs are issued for each MWh of eligible renewable generation located within or delivered to the Texas grid. With the exception of renewable power plants with a capacity smaller than 2 MW, which are eligible irrespective of their vintage, the REC trading program is

[4] The level of the standard was established in a political setting, and was viewed at the time as being an aggressive but achievable target.
[5] Based on an assumed average capacity factor of 35%. Assuming an average annual growth in demand of 3% this translates to a renewable energy share of 2.2% by 2009.
[6] DOE (2000) estimates that wind power alone in Texas has the resource potential to deliver over 400% of the state's present electricity consumption.

restricted to facilities erected after September 1, 1999. A wide variety of renewable technologies are eligible. Table 1 summarizes the design features of the policy.

Table 1. The Texas RPS: Design Details

Design Element	Design Details
Renewable energy purchase obligations	capacity targets of 400 MW of eligible new renewables by 2003, 850 MW by 2005, 1400 MW by 2007, and 2000 MW by 2009 and through 2019 annual energy-based purchase obligations beginning in 2002 and ending in 2019 derived based on capacity targets and average capacity factor of renewable generation (initially set at 35%)
Obliged parties	all electricity retailers in competitive markets (80% of total Texas load) share the obligation based on their proportionate yearly electricity sales; publicly-owned utilities must only meet the RPS if they opt-in to competition
Eligible renewable energy sources	new renewable power plants commissioned after September 1, 1999 and all renewable plants less than 2 MW capacity, regardless of date of installation power production from solar, wind, geothermal, hydro, wave, tidal, biomass, biomass-based waste products, and landfill gas are eligible purchases of renewable energy from plants larger than 2 MW and built before September 1999 may count towards a supplier's REC obligation, but are not tradable power must be located within or delivered to the Texas grid renewable energy sources that offset (but do not produce) electricity (e.g., solar hot water, geothermal heat pumps), and off-grid and customer-sited projects (e.g., solar) are also eligible
Tracking and accounting method	tradable RECs with yearly compliance period 3 month grace period after compliance period allowed for fulfillment
Certificates	issued on production, unit 1 MWh, 2 years of banking allowed after year of issuance, borrowing of up to 5% of the obligation in first 2 compliance periods allowed, development of web-based certificates tracking system*
Regulatory bodies	Texas Public Utilities Commission establishes RPS rules and enforces compliance; ERCOT Independent System Operator serves as REC trading administrator
Enforcement penalties	the lesser of 5(US)¢ or 200% of mean REC trade value in compliance period for each missing KWh

* Some countries, notably Denmark, have considered establishing a price floor for RECs. No U.S. RPS has included this design feature.

3. Early Achievements: The Texas Wind Rush

3.1 Renewable Energy Development

Though RPS obligations do not begin until 2002, the announcement of the RPS in 1999 and the subsequent completion of implementing regulations have already propelled Texas to one of the largest renewable energy markets in the United States. Consider:

- Over ten wind projects – the largest of which is 275 MW in size – totaling 930 MW have been erected in the state thus far in 2001 or are planned for completion by the end of 2001.
- 12 new landfill gas projects with 44 MW of total capacity have been announced.
- Approximately 50 MW of hydropower renovations are planned in the near future.
- 2650 MW of wind projects have applied for grid access, providing an indication that growth in wind capacity is unlikely to stall at the 930 MW already well on its way to completion.

Given these results, it is evident that the RPS capacity targets for 2003 (400 MW) and 2005 (850 MW) may be met several years early. Table 2 lists the expected RPS obligations of Texas retail electricity suppliers in 2002, and the wind contracts that have been signed to date (through October 2001). It should be noted that the latter four utilities in the table have no RPS obligations in 2002. Their commitments to wind power are driven, instead, by customer preferences for renewable energy and/or utility resource planning decisions.

Table 2. RPS Obligations and Wind Contracts for Retail Suppliers

Electricity Supplier	Approx. 2002 RPS Obligation (MW)	2001 Wind Contracts (MW)
TXU	170	353
Reliant	140	208
AEP	0	0
Entergy	0	0
Excel-SPS	40	80
TNP	2	3
Enron	15	130
Other New Players	33	?
Austin	0	80
LCRA	0	50
San Antonio	0	25
El Paso	0	1
TOTAL	**400 MW**	**930 MW**

Source: Updated through October 2001, and derived from Sloan (2001)

3.2 Technology Selection and Cost Reductions

Wind power projects are the most competitive of all RPS-eligible renewable energy technologies in Texas at the moment, as untapped landfill gas resource opportunities are limited and hydro resources are nearly fully exploited. Solar generation and traditional forms of biomass energy are too costly in Texas to compete with wind power at this time. Most of the planned wind power plants are located in West Texas, where average annual wind speeds of 8 m/s are common and capacity factors can exceed 40%. The sizable purchase obligation under the RPS also allows wind projects to gain the economies of scale necessary for deep cost reductions. Combine this factor with the outstanding wind power resource and with the federal 1.7(US)cent/kWh production tax credit (PTC), and wind power projects in Texas are able to deliver power to the grid for less than 3(US)¢/kWh.

That the initial RPS targets are to be exceeded may therefore come as little surprise: wind power in Texas, with the PTC, is close to competing on purely economic grounds against new natural gas facilities, even with relatively low natural gas prices. With early over-compliance with the purchase standard and compliance costs that are at low levels given the competitive pricing offered by renewable generators, there have been calls for increasing the policy's renewable electric capacity goals.[7]

3.3 Long-Term Contracting

An equally important achievement under the Texas RPS is that obligated electricity suppliers have been willing to sign long-term (10-25 year) contracts for RECs and the associated electricity. Without long-term contracts, renewable energy developers are faced with the unenviable position of developing merchant renewable energy projects with highly uncertain returns (Wiser and Pickle 1997, Helby 1997, Langniss 1999). Similarly, electricity retailers risk not being able to procure the requisite number of RECs by year's end or only being able to procure credits at astronomical prices due to supply constraints or market manipulation.

Long-term contracts, on the other hand, ensure developers a stable revenue stream and access to low-cost financing, while delivering to electricity retailers a reliable stream of renewable electricity at stable prices. In fact, though renewable developers are often able to choose between REC-only sales and sales that combine the RECs and electricity, virtually all contracts to date have covered both the certificates and the electricity. This clearly demonstrates the importance of reducing revenue-risk on the part of developers. Retail electricity suppliers also have a strong incentive to bring renewable energy projects on line quickly under long-term contracts and with locked-in prices: with the PTC for wind power currently slated to expire at the end of 2001, REC prices may well rise in the future.

A final component of the long-term contracting process in Texas deserves mention. To shield risk on the retail suppliers' end that REC costs will increase and/or that the supplier will fail to comply with the RPS, contract terms strongly penalize project construction lags and operational problems. This can be clearly seen in Table 3, where we list the standard contract provisions for two utilities as expressed through RFP documents.[8] Unlike competitive bidding situations in the U.K. under the Non-Fossil Fuel Obligation and in California under its system-benefits charge

[7] It should be noted, however, that the PTC is currently slated to expire after 2001. Though an extension of the policy appears likely, were it not extended RPS compliance costs in Texas would increase and other renewable technologies may better compete for a share of the RPS market with wind power.

[8] The security requirements imposed by retail suppliers favor renewable energy developers or development teams with strong financial backing.

policy (Mitchell 2000, Bolinger et al. 2001), there is little incentive in Texas for developers to propose projects that do not have high probability of completion.[9] In fact, such bidders will either be unsuccessful in garnering a contract or could face severe penalties if they were able to secure a contract. This may be an important advantage to the RPS approach.

With renewable electricity prices hovering around or below 3(US)¢/kWh and numerous closely matched projects vying under each competitive solicitation, competition for cost-competitive renewable energy supply in Texas is working.[10]

3.4 Certificates Tracking System

A final milestone of achievement in Texas is the development of a web-based platform for the administration of the REC program. This platform – which will allow for the issuance, registration, trade, and retirement of RECs – was established in May 2001. The platform will facilitate tracking RPS compliance, but will not provide the "market making" function of a certificate exchange, as this function is to be the left to the private marketplace, as will REC brokering and financial markets.

Certificate-only trades have only just begun as RPS quotas do not apply until 2002 and a substantial amount of the initial certificates are bundled in long-term "electricity plus certificates" forward contracts through bilateral trades. As compliance obligations begin, trade of surplus certificates can be expected to increase and a secondary market may develop (Fabri 2001). A certificates exchange may also develop with time, though at present there are no announced plans for such an exchange; virtually all existing transactions have been bilateral ones that have included RECs and electricity, with a few brokered REC-only transactions. The price of certificates is currently expected to equal approximately 0.5(US)¢/KWh during 2002, and this price has been realized in the few "off system" REC-only trades that have occurred to date.[11] With substantial oversupply of renewable energy relative to RPS obligations and with "electricity plus certificates" contracts at or below 3(US)¢/kWh, however, it is unclear whether even this REC price will be sustained.[12]

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[9] In both the U.K. and California, a substantial number of the new renewable energy projects that won bids under the Non-Fossil Fuel Obligation (UK) and the production-incentive auction (California) have never been developed. This result is partly due to the design of each policy, where a certain degree of speculative bidding by renewable energy developers has been allowed.

[10] The prices under these contracts are often fixed over the entire contract term, though a fixed annual escalation is sometimes applied. We note that the cost-competitive pricing offered relies on the availability of the PTC.

[11] As of mid-September 2001, at least two small, brokered REC-only trades have been completed (Fabri 2001). Both trades were brokered by Natsource LLC and in both cases the REC purchaser is not a retail supplier with RPS compliance obligations (i.e., they are off-system trades). Both trades are also one-time purchases. The first trade, a sale of just under 1000 MWh of RECs that traded at 0.6(US)¢/kWh, went to a European buyer interested in reselling the RECs in their own market. The second trade – less than 500 MWh of RECs at 0.5(US)¢/kWh – went to an energy company for public relations reasons.

[12] Three forces that may keep prices in this range are: (1) the potential for off-system trades such that REC demand (even if occurring outside of the Texas RPS) catches up with REC supply, (2) the possibility of market power in the REC market, with just a few utilities initially contracting for a majority of the RECs in circulation, and (3) reduced natural gas prices, which increases the relative, incremental cost of renewable energy. REC banking may also support higher REC trading values, as RECs can have value in future compliance periods.

Table 3. Elements of Typical Renewable Energy Contracts

Proposed Provisions	**TXU**	**SPS**
Requested product	RECs or RECs & associated energy	RECs or RECs & associated energy
Quantity	approx. 500,000 MWh/yr total; 1,000 MWh/yr minimum quantity of individual proposals to minimize administrative burdens	approx. 123,560 MWh/yr total; no minimum quantity of individual proposals
Term	10 years*; start date must be before 2002	15 years; start date must be before 2002
Options for term extension	buyer may opt twice for 4 additional years	none**
After termination	option to purchase facility at fair market value	no provisions
Annual amount	fixed over the contract term; must sell all electric production including excess amount to buyer (if bid for RECs and associated energy)	fixed over the contract term; must sell all electric production including excess amount to buyer (if bid for RECs and associated energy)
Contract purchase price	one price for the entire term; price may vary for each option period	fixed by contract for every year
Definition of excess amount	> 105% of contracted amount	> 110% of contracted amount
Purchase price for excess amount	50% of the usual contract price	50% of the usual contract price
Penalty for under-performance	5(US)¢/kWh payment for consistent production less than annual amount	5(US)¢/kWh payment for consistent production less than annual amount
Security required once a project is short-listed for contract consideration	irrevocable letter of credit or comparable for 2 years, 0.5(US)¢/kWh based on yearly production	irrevocable letter of credit or comparable for 2 years, 0.5(US)¢/kWh based on yearly production
Security required once a purchase contract has been finalization	0.5(US)¢/kWh based on yearly production to cover under-performance penalties, etc.	5(US)¢/kWh based on yearly production to cover under-performance penalties, etc.
Construction requirements	projects only selected if have demonstrated business and technical expertise to deliver on time and within contract requirements	projects only selected if high probability of timely construction; monthly progress reports; penalties for not meeting construction milestones
Operation requirements	adequate staff for operation required; transmission and ancillary services handled by buyer if RECs & associated energy; timely maintenance and status updates	joint development of operating procedures; timely maintenance and status updates; minimum performance requirement (> 90% availability)

* Terms as short as 5-yrs appeared to be allowed in initial documentation, later to be replaced with a 10-yr term.

** The possibility of a three-year extension was included in the RFP, but later abandoned in the model contract.

Source: Public requests for proposal documents from two Texas utilities, TXU and SPS. We note that these are proposed contract requirements. Actual contracts may differ somewhat.

4. Success Factors: The Devil is in the Details!

Though there are numerous ways of effectively structuring an RPS, certain fundamental policy design principles must be followed if an RPS is to function at low cost and with maximum impact. Of particular importance is that the RPS must provide sufficient confidence to renewable energy developers and retail electricity suppliers to ensure long-term, least-cost investment in renewable energy facilities. As shown in Text Box 1, a number of other state RPS policies have failed or appear likely to fail in this respect. The early successes of the Texas RPS, on the other hand, can be largely attributed to several positive design and implementation features of the policy.

- **Strong Political Support and Regulatory Commitment.** Strong legislative support for the RPS and a committed Public Utilities Commission charged with implementing the RPS ensured that the policy's design details were carefully crafted.[13] Such strong support and commitment have not been evident in several other U.S. states' RPS policies, where implementation details are often poorly designed and languish in uncertainty.

- **Predictable Long-Term Purchase Obligations that Drive New Development and Economies of Scale.** The size and structure of the Texas RPS ensures that new renewable development will be required to meet suppliers' REC obligations beginning in 2002. The standard increases gradually over time, and offers developers adequate time to develop their projects before the REC obligation begins. The standard applies to the majority of retail electricity load in Texas, ensuring a degree of competitive neutrality. Capacity targets are translated into performance-based renewable electricity purchase obligations to encourage high levels of project performance. The target, at 2000 MW in 2009, continues at the same level for an additional 10 years, ensuring projects adequate time to recover their capital costs. Intermediate targets are sizable enough to allow large-scale renewable energy development and, through economies of scale, reduce costs dramatically.

- **Credible and Automatic Enforcement.** Retail electricity suppliers that fail to meet their RPS obligations are faced with sure and strong penalties: the penalty for non-compliance is set to the lesser of 5(US) cents per missing kWh or 200% of the mean trade value of certificates in the compliance period. It does not pay to delay compliance, and retail suppliers have ensured their ability to comply by inserting penalty provisions in their renewable energy contracts so projects come online on schedule and operate within specifications. The strong political commitment to the policy and an effective enforcement mechanism provides the support necessary to support low-cost, long-term contracting. While the 5(US)¢/kWh penalty also acts as a cost cap to the policy, there is no evidence that this cap will be reached.

- **Flexibility Mechanisms.** Though enforcement of non-compliance will be swift and sure, adequate flexibility is build into the policy to ensure that suppliers have every opportunity to meet their obligations in a cost-effective fashion. A yearly compliance period, a 3-month

[13] One reason for this strong commitment to the success of the policy is that earlier polling in Texas showed surprising strong support for developing renewable energy among the state's residents.

"true up" period, REC banking for 2 years after the year of issuance, a 6-month early compliance period in 2001,[14] and allowance for limited REC borrowing all offer the necessary flexibility. Given the degree of over-compliance likely at least in the initial years of the Texas RPS, it appears as if REC banking in particular will be commonplace.

- **Certificate Trading.** Though certificate trading may not be essential for the effective design of a state RPS, and little trading has yet taken place in the Texas market, a REC system should ease compliance demonstration and tracking, improve liquidity in the market, provide additional flexibility to suppliers, and lower the overall cost of policy compliance. The Texas RPS features the first such REC tracking system in operation in the United States.

- **Favorable Transmission Rules and Siting Processes.** Though the RPS is the principal driver in the growth of the Texas renewable energy market, other features of the Texas market facilitate RPS compliance at low cost and with limited hurdles. First, with a world-class wind resource and limited wind power siting constraints, wind projects can be built in large increments, capturing cost reductions due to economies of scale. Second, though severe transmission capacity limits may initially constrain wind development in West Texas, the state has established favorable transmission planning and costing approaches that will benefit renewable generation and that may prevent ongoing congestion.[15]

- **Production Tax Credit.** Finally, the federal PTC for wind projects also significantly reduces RPS compliance costs. Moreover, the fact that the PTC is currently only available for plants erected before the end of 2001,[16] and that REC prices may increase in the future if the PTC is not extended, provides every incentive for early RPS compliance and long-term contracting between retail electricity suppliers and renewable energy projects.

[14] Though REC purchase obligations do not begin until 2002, to help ensure RPS compliance, RECs generated during the later half of 2001 can be used to meet 2002 compliance obligations.
[15] Texas is aggressively strengthening its transmission system and, as in many European countries, grid expansion costs are paid by Texas electricity customers rather than by the power plant operator. Moreover, fees to recover the embedded costs of existing and new transmission infrastructure are placed on electricity consumers based on a flat fee, or postage stamp approach independent of the location of production or consumption (congestion costs will also be charged). A standard interconnection process has been established. Scheduling rules and requirements for intermittent generation are also relatively favorable.
[16] The PTC may be extended, however, as wide bipartisan support for the policy has been achieved.

Text Box 1. Design Features of Other U.S. RPS Policies

Ten U.S. states have recently implemented renewable energy purchase requirements, often (but not always) as a component of electricity reform: Arizona, Connecticut, Maine, Massachusetts Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin. Though some successes are beginning to emerge from Arizona and Wisconsin, and there is much hope for the standards in Massachusetts, Nevada, and New Jersey, few of these policies have been operable for more than a year and several have not yet begun.

More importantly, the RPS policies in several of these states do not contain the same strong provisions as those established in Texas, and may do little to instill confidence in the renewable energy industry. While we do not detail the RPS designs of each state here, a few illustrative examples show the importance of careful RPS design (see Rader 2000 for more information).

The most important problems experienced in U.S. RPS design include:

- **Inadequate attention to the relationship between the renewable energy purchase requirement and eligible renewable energy sources.** For example, Maine established a 30% RPS. Though this represents the highest RPS in the world, eligible resources include the vast majority of renewable energy and high-efficiency natural gas cogeneration in the New England region. Existing supply therefore far exceeds the standard itself. As a result, the RPS will do nothing to support new renewable energy development, and is unlikely to do much to support existing supply either.

- **Selective application of the purchase requirement.** Several U.S. states only apply the RPS to a small segment of the state's market, muting the potential impacts of the policy. For example, in Connecticut the utilities that deliver energy to customers that do not switch to a new electricity supplier are exempt from the purchase requirement. Not only does this approach violate the principle of competitive parity, it also ensures that the RPS will have only a marginal impact, as the vast majority of customers have shown no interest in switching suppliers.

- **Uncertain purchase obligation or end-date.** Another common concern is the uncertainty in the size of the purchase standard and its end-date in some U.S. states. In Maine, for example, the RPS is to be reviewed every five years. In Connecticut, when and how the RPS will end is simply unclear. Such uncertainty limits the ability of renewable generators to obtain reasonably priced long-term financing.

- **Insufficient enforcement of the purchase requirement.** Without adequate enforcement, retail electricity suppliers will surely fail to comply with the RPS. In this environment, renewable energy developers will have little incentive to build renewable energy plants. At best, the enforcement rules of a number of U.S. RPS policies are vague in their application: these include those policies in Connecticut, Maine, and Massachusetts.

Though of substantially lesser importance, still other states have failed to implement a renewable energy certificate system for easily tracking and monitoring compliance with the RPS. States in this category include Maine, Connecticut, New Mexico, Pennsylvania.

5. Conclusions

Though the RPS has been hailed as the leading "market-based" approach to supporting renewable generation – and several countries have opted to replace traditional policy mechanisms with this new approach – little experience exists on RPS implementation. What is becoming clear from the little experience that does exist is that, like any renewable energy policy, an RPS can be designed well or it can be designed poorly. Experience in several U.S. states shows that inadequate purchase obligations, overly broad renewable energy eligibility guidelines, unclear regulatory rules, insufficient enforcement, and wavering political support can all doom an RPS to certain failure.

And yet the Texas policy shows that an RPS, if properly designed and carefully implemented, can deliver on its promise of offering a low-cost, flexible, and effective support mechanism for renewable energy. The Texas wind rush is likely to drive half of all wind development in the United States in 2001, and there is some evidence that this rapid development path will continue for some years to come.

To be sure, this wind power boom is not solely an outgrowth of an effective RPS policy. A developing customer-driven market for green power and the wind power plans of electricity utilities not subject to RPS requirements have also driven some of the development. The federal PTC for wind, favorable transmission rules, and an outstanding wind resource have additionally played important roles. Such complementary policy and market mechanisms are nearly always essential for effective renewable energy deployment. In fact, it should be re-emphasized that the Texas RPS is largely supporting the development of the lowest cost renewable energy technology – wind power. Other U.S. states have developed additional policies to ensure a diversity of renewable energy supply options.

Nonetheless, it can be said with near certainty that, given previous development plans, the major driver in the resurgence of wind energy development in Texas has been the state's aggressive RPS. Other countries and U.S. states would be well-served to study carefully the successful efforts of RPS design in Texas.

Perhaps the most intriguing element of the Texas RPS is that it obliged electricity suppliers to deal with wind power and other renewable energy sources on a large scale and in a proactive fashion. Growing industry confidence in these technologies seems unavoidable, and electricity suppliers are beginning to realize that sizable wind projects in Texas, with the PTC, are sometimes able to compete on an equal footing with other, more traditional generating sources. While the 2000 MW purchase obligation established by the RPS will provide a good footing for initial development, a maturing wind industry able to compete at or near the cost of natural gas will surely offer more substantial market opportunities over the long term.

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EXHIBIT 2

AFFIDAVIT OF CRAIG MATACZYNSKI

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

BEFORE ME, the undersigned Notary, Meredith L Lawrence on this 6 day of April, 2006, personally appeared Craig Mataczynski, the President and Chief Operating Officer of Renewable Energy Systems Americas, Inc. ("RES-Americas"), a Delaware corporation, known to me to be the person ("Affiant") whose name is subscribed below, to be a credible person and of lawful age, and who, being by me first duly sworn, did on his oath state as follows:

1. Affiant. The name and business address of Affiant is:

   Craig A. Mataczynski
   9050 Capital of Texas HWY
   Suite 390
   Austin, Texas 78759

2. Affiant's Elected Position With RES Americas. President and Chief Operating Officer

3. Business Activities of RES Americas. RES Americas, based in Austin, Texas, is an affiliate of Renewable Energy Systems Ltd. ("RES"), a company based in the United Kingdom. RES was founded in 1981 to construct and develop renewable energy projects and has been active in the US since 1995. RES has over 6,000MW of renewable energy projects in various stages of development worldwide. RES Americas has constructed and developed more the 700MW of wind power in the State of Texas and has constructed and developed more than 1300MW of wind power in the United States, including a small wind farm in the Commonwealth of Pennsylvania. RES Americas' activities represent approximately 12% of the wind energy facilities built in the United States.

4. Has RES Americas entered into any long-term contracts in the State of Texas? RES Americas is a significant market participant in the wind market of Texas. As of the end of 2005, all of the output of RES Americas' development projects in the State of Texas has been sold under long-term power purchase agreement (PPA) with Texas load serving entities. Because RES Americas constructs wind farms in addition to developing such facilities, we do business with many of the other entities developing wind facilities in Texas and elsewhere in the United States. It is our understanding that most of the wind developers in Texas have entered into or are striving to enter into long-term PPAs for the output of their wind farms.

5. <u>How important are long-term contracts for the development of wind power projects?</u> Long-term contracts are an important part of any renewable market structure because they mitigate the price uncertainty and risk associated with developing renewable projects, ultimately driving down the costs to developers and consumers and encouraging development. Without long-term contracts, it becomes questionable whether a renewable developer will be able to obtain the financing necessary to develop and construct a wind farm. Even if such a developer is able to secure financing, the higher risk of such a project will demand a higher cost of capital to build. Lenders will seek higher yields for debt instruments, and equity interests will demand higher returns to compensate for risk. Driving up the capital costs, ultimately drives up the cost of delivering renewable energy to the consumer. In other words, risk costs consumers money. It also makes renewable energy less commercially attractive than other types of generation, creating a dis-incentive for renewable energy which is contrary to the desires of the Commonwealth of Pennsylvania.

Some have argued that a vibrant renewable energy credit (REC) market without long-term contracts will be sufficient to attract the desired renewable investment in Pennsylvania. RES' experience in Texas and elsewhere is that RECs, even with a vibrant trading platform, are inherently volatile. RECs have a tendency to act like a light switch. If a particular state or market is short of the required RECs, then the REC prices will be at or near the penalty price set by that particular state or market. If a particular state or market has an ample supply of RECs, then the REC prices will quickly lose the majority of their value. In contrast, long-term contracts have a tendency to value the REC component of green power on a longer term view of the market, and typically price RECs somewhere between the highs and lows of the market. The only entities that gain from volatility in the REC market are marketers that will attempt to extract a premium by trading around or hedging the volatility, or high risk equity investors who are taking a short term position in a market and are seeking to make high returns by taking high risks.

6. Conclusions:

Long-term contracts are an important part of renewable development because they reduce costs to both developers and consumers and help developers finance projects. Without long-term contracts, the ability to finance renewable projects becomes questionable. Making it easier to finance renewable projects will help attract renewable development in the Commonwealth of Pennslyvania, and will help the Commonwealth meet its renewable objectives. For these reasons, RES strongly recommends that long-term contracts be an integral part of the Commonwealth of Pennsylvania's renewable market structure.

_______________ [signature]

Craig A. Mataczynski
9050 Capital of Texas HWY
Suite 390
Austin, Texas 78759

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

SUBSCRIBED AND SWORN BEFORE ME by Craig Mataczynski, President and Chief Operating Officer of Renewable Energy Systems Inc, a Delaware corporation, on this 10 day of April, 2006, on behalf of said corporation.

MEREDITH L. LAWRENCE
Notary Public, State of Texas
My Commission Expires
March 04, 2009

Meredith L. Lawrence
Notary Public in and for the State of Texas

My commission Expires:

March 04, 2009

EXHIBIT 3

Uniform-Price Auctions in Electricity Markets

Peter Cramton and Steven Stoft[1]

20 March 2006

Abstract

Wholesale electricity markets are commonly organized around a spot energy market. Buyers and suppliers submit bids and offers for each hour and the market is cleared at the price that balances supply and demand. Buyers with bids *above* the clearing price pay that price, and suppliers with offers *below* the clearing price are paid that same price. This uniform-price auction, which occurs both daily and throughout the day, is complemented by forward energy markets. In practice, between 80 and 95 percent of wholesale electricity is traded in forward energy markets, often a month, or a year, and sometimes many years ahead of the spot market. However, because forward prices reflect spot prices, in the long run, the spot market determines the total cost of energy. It also plays a critical role in the least-cost scheduling and dispatch of resources, and provides an essential price signal both for short-run performance and long-run investment incentives. Arguments that the uniform-price auction yields electricity prices that are systematically too high are incorrect. However, insufficiently hedged spot prices will result in energy costs that fluctuate above and below the long-run average more than regulated prices and more than is socially optimal. Tampering with the spot price would cause inefficiency and raise long-term costs. The proper way to dampen the impact of spot price fluctuations is with long-term hedging. Although re-regulation can provide a hedge, there are less costly approaches.

Introduction

Recent large electricity price increases have led some to conclude that wholesale electricity markets have failed. The uniform-price auction, used to balance supply and demand in the spot energy market, is often suspected as the culprit.[2] In this spot market, buyers and suppliers submit bids and offers for each hour and the market is cleared at the price that balances supply and demand. Buyers with bids at or above the clearing price pay the clearing price for the quantity purchased. Suppliers with offers at or below the clearing price are paid the clearing price for the quantity sold. Thus, a nuclear supplier with a marginal cost of $20/MWh would be paid $80/MWh for its quantity sold in the spot market, whenever the clearing price happened to be $80. Indeed, all suppliers are paid the *highest* variable cost among all those supplying spot energy.

Doesn't such a system cause consumers to systematically overpay for electricity? *Absolutely not*. Indeed, the clearing-price auction is an essential feature of any electricity market designed to reliably provide consumers electricity at minimum cost. The clearing-price auction plays a critical role in the least-cost scheduling and dispatch of resources, and provides an essential price signal both for short-run performance and long-run investment incentives.

What then is responsible for the recent large increases in electricity prices? This is an important question and deserves an answer that goes deeper than an examination price formation in the spot market. Several long-run issues must be understood before the role of the spot market can be correctly evaluated. Without this, there may be an incorrect assignment of blame and recommendations for changes that would prove costly in the long run. These are the factors—from most important to least important—at work in the present situation.

1. Fuel prices increasing sharply
2. The removal of some retail price caps, an artifact of restructuring settlements
3. Changes in relative fuel prices, resulting in short-run disequilibrium
4. Insufficient long-term forward contracting
5. The law of one price
6. The uniform-price auction used in the spot market

The first three factors are the drivers of present market developments; the last three concern the way the market responds to external forces. Rather than begin with an examination of a uniform price action, it is better to examine first why this has become a concern. A stylized description of recent events will serve to highlight the principles involved and explain the main effects. Since electricity markets opened in 1998, the power industry has developed as follows.

Stage 1: Overbuilding followed by high gas prices. At first, gas prices were low and gas-fired generation appeared cheaper than alternatives. In a competitive market, this opens the door to high profits for companies that build new gas-fired plants. But this door will only stay open until a new equilibrium with sufficient gas generation has been reached. This led to a flood of new gas-fired plants. But investors soon faced two unpleasant surprises. Wholesale prices were kept lower than they expected and gas prices shot up. The result was a complete reversal. There are now too many, not too few, gas-fired plants and they are relatively expensive, not relatively cheap.

The new disequilibrium produces new winners and losers. First, owners of gas-fired plants are clearly hurt. There is too much capacity and wholesale prices have been suppressed by mitigation rules. The result is that gas-fired plants recover little of their fixed costs and experience a windfall loss. This loss is a windfall gain for consumers. Because gas prices are high and because the wholesale price is frequently set by gas plants, cheaper plants, nuclear and coal plants, experience a windfall gain. When the wholesale price is \$80, those with \$20 variable costs collect \$60 towards their fixed-cost recovery. This has proved to be more than enough. This windfall gain to baseload plants is a windfall loss to consumers.

So far, the net impact on consumers is unknown. Two effects have worked in favor of consumers: (1) the market has been overbuilt, and (2) market rules have held peak prices somewhat below a long-run competitive level. But the disequilibrium effect has worked against consumers. It seems likely that at first consumes received a net benefit, but are now on the losing end of the cycle. But markets are never static, and this is changing. The market is signaling for the *entry* of new baseload plants, but for a *halt* to gas-fired plant construction. In reality, the construction of new baseload plants will be slow, but the halt of investment in new gas-fired plants was quick and complete. The net result will be a tightening of supply and an increase in wholesale prices.

This price increase, due to a tightened supply, has as yet had little impact. Instead the current price increases are driven by increased fuel costs and changes in regulated retail price caps. These changes are readily understood, and consequently this paper will continue to focus on the deeper economic issues, which are pertinent to the controversy over the uniform-price spot market.

Stage 2: High gas prices without surplus capacity. In the coming stage of the market, we cannot be sure of the price outcomes, but it is entirely possible that gas-fired plants will again break-even, baseload plants will increase their windfall gains, and consumers will suffer windfall losses for some time to come. This will only exacerbate present difficulties. That outcome could result from the following dynamic. New capacity will be needed to match load growth. If there are barriers that slow the entry of baseload plants, the new entry will need to be gas-fired peakers and shoulder plants. These will only enter if the current and future profitability of gas-fired plants increases to the break-even level. The new ICAP market rules will allow this, and thereby prevent a shortage of capacity and blackouts, but in doing so, they will raise revenues for all types of plants, peakers, shoulder, and baseload.[3]

There is no certainty this will happen, and this paper is not predicting it, but simply pointing out that it is possible. This possibility is relevant because it is apparently the essence of the fear behind the criticism of uniform spot prices. By making it explicit, that fear can be addressed analytically. The problem, then, is that the market could, for a few years, produce an outcome in which consumers experienced a windfall loss as the result of nuclear and coal plants experiencing a windfall gain. This raises a number of questions that have not been well addressed in the discussion of deregulated electricity markets. Are windfall gains and losses for consumers a normal part of a well functioning market? How should these be controlled? Are the windfalls of Stage 2 the result of a well-functioning market, or of market flaws? Short versions of our answers may be helpful before delving into the analysis.

1. Well functioning markets do produce windfall gains and losses for consumers as well as for suppliers. On average, consumers pay only long-run cost, neither more nor less.
2. Windfalls can be controlled as well in a market setting as in a regulated setting. This is done with long-term contracts.
3. The windfalls of stage two are due to insufficient long-term forward contracting, and may be exacerbated by barriers to entry against certain types of plants.

Spot markets, forward markets, and uniform prices

The hypothetical Stage 2 outcome, with windfall profits for baseload plants, is primarily the result of fundamental economic forces. The relative prices of gas and coal, and of gas and uranium changed dramatically in a short time. In a market with long-term capital assets and incomplete hedging, such price changes produce a windfall for the supplier using the fuel type that has gained the advantage. This has nothing to do with the intricate details of the spot market.

In part, this is a benefit of a market. It pays extra profits to those who invest in the low-cost technology, in this case, new nuclear or coal plants. This stimulates good investment and lowers long-term costs. *It is essential that the spot market operate in this way*; otherwise investors will have no reason to choose wisely. The agreement on this is near universal. But what is the implication for existing plants? Does the spot market need to pay windfall profits to existing plants or only to new investments?

Separating existing from new. It is necessary for better plants to be more profitable, otherwise the market can provide no guidance for building better plants. But once they are built, it may seem unnecessary to continue this guidance. This is the seeming paradox at the heart of the sensible question concerning a uniform-price spot market. There is also another question which causes confusion: Why shouldn't we try to hold everyone's spot price down to their variable cost. This will be taken up in detail later, but the answer is virtually self-evident—because no investor would ever build a plant if fixed costs were not recovered. When the market is in equilibrium, uniform prices simply cover variable plus fixed costs. That cannot be argued with. But the question of paying windfall gains through a uniform-price spot market is much deeper, and deserves serious attention.

Suppose we have a power market that is competitive, well designed with a uniform-price spot market, and in equilibrium with respect to the types of generating capacity that it has in place. It will pay all plants just enough to cover their fixed and variable costs. Now suppose the price of gas quadruples and all gas plants are on the margin, and so set the spot price, one-half the time. This will not help gas plants, which face much higher fuel costs, but it will raise revenues for nuclear plants enormously without any corresponding increase in production costs, because the price of uranium is unrelated to the price of gas. What should be done about this? Two courses of action are suggested: (1) pay nuclear plants less than the market-clearing spot price, or (2) remind under-hedged load serving entities (LSEs) that they should have more long term contracts. If most LSEs are not well hedged, this may be a painful choice, but it is the choice we must examine.

Consequences of price discrimination. Ignore the possible legal problems (antitrust laws prohibit price discrimination in wholesale markets), and consider a discriminatory spot market in which nuclear plants would be paid only enough to cover their fixed and variable costs. This might be done by capping their spot price at the level the price would have been without the gas price increase. Although that is not easy, for simplicity let us assume it is possible. What are the consequences? First, in the short-run, there is certainly no problem. Existing plants will more than cover variable costs, and so will still have an incentive to provide electricity. Second, existing nuclear plants will continue to earn a normal rate of return, despite the high gas price.

However, it is insufficient to focus solely on the short run. Markets must also provide the right incentives for long-run investment. What will happen in the long run? That depends on the unspoken part of this new policy of capping profits at a normal level. What will be done when things go the other way for nuclear plants and they come on hard times? What if gas prices, rather than quadrupling, are halved? Again two possibilities must be considered: (1) their spot prices will be adjusted up above the market-clearing prices so that their profits stay at the normal level, or (2) they are given the market-clearing price and suffer a windfall loss.

But now we see the problem. Holding their profits constant by always adjusting their spot price is just rate-of-return regulation. Regulating all nuclear plants so that they always make a normal rate of return will completely remove the market's investment signals. Investors will know that no matter how many such plants have been built they can always build one more and make what the regulator has determined to be a normal rate of return. Hence, if investors like this rate of return, they will just keep building, and if they do not, they will not build any more. This will force the regulator to take over the investment decision, and a principal benefit of moving to competitive electricity markets would be lost. This shows that preventing the signals of a uniform-price spot market, if done carefully, simply leads back to rate-of-return regulation.

One caution is in order and it foreshadows the coming analysis. If the nuclear plant has sold its power under, let us suppose, a ten-year contract for differences, for the original equilibrium average price, then imposing a regulated low spot price will impose on it an enormous windfall loss. Its customer will be paying high spot prices, and the nuclear plant will have to make up the difference between those and the contract price while not getting paid the high spot price itself. This could be remedied by having the regulator take over the contract.

The second option for price discrimination is to cap the nuclear unit when it would make excess profit and pay it the uniform spot price when it would suffer a windfall loss. Under such a policy no investor will ever build a nuclear plant. They will know that the regulator will take their windfall gains and let them keep their windfall losses. Moreover, investors in every other type of plant will expect that if they make windfall gains, the same policy will likely be applied to them. Such a policy is much worse than either regulation or a competitive market. The result under such a policy is that the government is forced to purchase all new generating capacity, and in the long-run the electricity industry becomes a state-run enterprise.

Consequence of forward contracting. Long-term forward contracting is a more subtle approach to the problem. First consider what happens if existing nuclear plants have complete forward contracts. Suppose they have signed contracts with LSEs selling their average annual output for as long as the plant remains operational at the average price they receive in the ideal equilibrium before the gas price increase. In this case, existing nuclear plants will not profit at all from the gas price increase. This is the same as under the price discrimination proposal. But for new investors, there is a world of difference. Once the gas price goes up, a new investor can go to an LSE and offer to sell power from a new nuclear plant at a higher price than is charged by existing nuclear plants, but at a lower price than will be charged by gas plants. If there is only one nuclear investor, that investor can capture the entire windfall profit stream from the higher spot prices due to the gas-price increase. This provides a huge incentive for new investment.

So, with complete forward contracting, existing plants capture no windfall profits, but new plants can potentially capture up to all of them. What will happen? With more than one investor there will be competition and the price of power from the new nuclear plant will be bid down. With enough competition it will be only the slightest bit higher than the price of power from an existing plant. With complete forward contracting and near-perfect competition, there is no extra profit for nuclear plants, new or existing. In spite of this, the potential for nuclear profits if there is no new nuclear investment is so great that it assures investment—unless there is some strong barrier to entry. Hence, with complete forward contracting, the market does just what we want.

Let us look more closely at the uniform-price spot market. When gas prices go up, the spot price goes up, and nuclear plants are paid more whenever gas is on the margin. But since the plants have already sold their power, they cannot pocket the higher prices, but must use the extra revenue to make their customers whole. They may sell the power to customers directly at the low long-term price determined by their own costs. Alternatively, their customers may buy from the system operator at the high spot price, and the plant may sell at the high spot price, and then pay their customer the difference between the high spot price and the low long-term contract price. Either way, the existing nuclear plants make no windfall profits.

What if there are no forward contracts? Without forward contracts, does a uniform-price spot market over-charge consumers? Not on average. If the spot market provided suppliers with windfall profits on average, investors would be delighted and build plants with exuberance. We saw this in the early days of the market and the result was low profits or losses. This is the paradox that makes markets work. If profits are high, then profits will fall in response to entry. If they are low, no investor will enter and profits will rise in response to growth in demand. The result is that spot-market profits bounce around a bit, but they cannot be persistently high or low—on average the spot price is just right. However, there are two exceptions: (1) spot prices can be persistently too high if there are significant barriers to entry—then existing suppliers can enjoy windfall profits that correspond to the cost required to overcome the entry barrier, and (2) spot prices can be persistently too low if there are significant subsidies to suppliers of electricity. The result is that, absent entry barriers or subsidies, the suppliers will not, on average, make windfall profits, and consumers will not, on average, have windfall losses.

So, on average, the uniform spot price will be fair to both consumers and suppliers. What then, is the need for forward contracting? Forward contracts eliminate risk for both suppliers and consumers. They provide mutual insurance. If the nuclear plant is lucky and the consumer unlucky, the plant gives its winnings to the consumer. If the consumer is lucky and the plant unlucky, the consumer gives its winnings to the plant. In this way both are insured, and total risk is reduced. The reduction can be dramatic. Both consumers and investors view risk as a cost, so reducing both their risks reduces their costs. Competition will pass the cost savings on to consumers and leave suppliers, as always, with a normal rate of return that simply covers all their costs including the (reduced) cost of risk and normal fixed and variable costs. Hence consumers will find themselves with less risk and with more money in their pockets. This is one reason forward contracts matter.

The second reason lies a bit outside the scope of normal economics. Without forward contracts, consumers will, sometimes for years, experience below-long-run prices. This can happen for example when the market is overbuilt. They will become used to these and they will consider them the "right price." Then when their windfall losses come, there will be much noise and commotion, accompanied by the perfectly correct observation that prices are above the long-run average because certain plants are making windfall profits. The result will be attempts to interfere with the market design, quite likely by attacking the policy of a uniform spot price. On a particularly disruptive path, this may lead back toward regulation or may simply break the market's investment incentives and require high risk premiums to maintain reliability.

Does Regulation Handle the Problem Better? Regulation is a kind of long-term contract and consequently it has wonderful risk-reducing properties. Regulated costs may be too high, but there will be little profit risk and generally less risk of price-shocks for consumers. In terms of risk, it is much like the ultimate long-term contracts described above. Of course in either case one may sign a long-term contract for a technology the turns out to be too expensive, so there is still some risk. When comparing regulation with fully hedged markets, the difference lies primarily in the investment and performance incentives. Here the market has all the advantage.

Although economists like to assume optimal forward contracting because it makes the analysis simpler and the outcome rosy, real markets appear not to conform to this assumption. This presents a problem that cannot be solved analytically, and for which we have little data. If the market will not purchase enough long-term forward contracts, does the cost of additional risk outweigh the gain from better incentives? Generally economists judge the benefits of better incentives to outweigh the cost of additional risk, and choose markets over regulation unless there is some overriding consideration.

If the market path is followed, this analysis leads to one clear positive recommendation. Reduce market risk. This does not mean to reduce performance risk, as that would remove the incentives that are the entire point of using a market. Much risk can be eliminated with a well designed capacity market,[4] but this will not eliminate the risks caused by shifts in relative fuel prices. These risks need to be hedged by long-term contracts between generation and load. Encouraging such contracts is not simple, but it is the proper focus for as long as a market course is pursued. This will improve the market, whereas tampering with the uniform spot price could destroy it.

Changing the energy spot market from uniform-pricing to pay-as-bid pricing does not help, and probably hurts

Some have proposed to replace the uniform-price auction with a pay-as-bid auction. The argument is that with a pay-as-bid auction, a supplier would be paid an amount that more closely corresponds to the supplier's cost. Thus, a nuclear unit with a marginal cost of $20/MWh would be paid something closer to $20, even when the clearing price is set by a gas unit with a marginal cost of $80/MWh. Such an outcome is simply wishful thinking; it would only occur if the nuclear unit were forced to offer at $20/MWh, rather than a profit maximizing offer, which would be much closer to $80 than $20, if a pay-as-bid auction were used.

The benefits of a uniform-price auction in organizing trade between buyers and sellers is well understood. Absent market power, the uniform-price auction yields a competitive equilibrium, and the competitive equilibrium is efficient: the outcome maximizes social welfare. At least in theory, the right quantity of electricity is produced by the least-cost suppliers, and this electricity is consumed by the buyers that value it the most.

Of course, real markets, including electricity markets, do not achieve the ideal of perfect competition, but there is a substantial body of theoretical and empirical work that shows that the convergence to full efficiency is rapid as a market becomes more competitive.[5]

Despite these virtues of a uniform-price spot market, can't prices be reduced by a switch to pay-as-bid pricing? This question has been a frequent source of debate and study by economists. In a nutshell, here are the theoretical, empirical, and practical answers.[6]

The theoretical answer is ambiguous. It depends on the particulars of the model. However, in the simplest cases, the answer is that it makes no difference. Both uniform-price and pay-as-bid approaches result in the same expected prices.

The empirical answer is consistent with theory. It depends on the particulars of the setting. However, the overwhelming evidence is that to the extent there are any differences in expected prices the differences are typically small and often insignificant.

From a practical perspective, there are a number of reasons that in the setting of electricity spot markets, uniform-pricing should be preferred.

First, the electricity spot market is a two-sided market in which both suppliers and demanders bid. The uniform-price auction has an obvious virtue in that the money paid by demanders is exactly equal to the money received by suppliers. In contrast, with the pay-as-bid format, the wedge between the winning demand bids and the winning supply offers is extra money paid by demanders, but not paid to suppliers. What is done with this extra money? [many readers may think extra money is more of a virtue than exact balance. Would it be correct to say that unless this money is returned to demanders, they will generally pay more under pay as bid, and if it is returned there will be squabbles over the rule? Just call this as you see it know need to discuss.] In the UK, which is the only market we are aware of that uses pay-as-bid pricing, the extra money is whimsically called "beer money." Although this "beer money" has steadily shrunk since pay-as-bid pricing was introduced, suggesting the law of one price is at work, it remains surprisingly large. However, closer examination of the market reveals that the source of the significant spread between seller offers and buyer bids are artificial transaction costs in the UK spot market intended to discourage its use.

Second, pay-as-bid pricing causes profit maximizing suppliers to estimate the clearing price and bid as closely to the clearing price as possible, whenever the clearing price is above the supplier's variable cost. The result is as-bid supply schedules that are all very flat and close to the expected clearing price. The problem is that there is uncertainty in the supplier's estimates of prices. Sometimes a low-cost supplier bids higher than a high-cost supplier, so that the high-cost supplier is asked to supply and the low-cost supplier is not. This happens because the supplier's bid has much to do with its guess about the clearing price and little to do with its cost. In contrast, with uniform-pricing, the primary determinant of a supplier's offer is the supplier's marginal cost. As a result, dispatch inefficiencies are much more common under pay-as-bid pricing than under uniform-pricing. In the long-run, dispatch inefficiencies raise costs, and these higher costs are ultimately passed on to consumers.

Third—and most subtle—uniform pricing is procompetitive in the following sense. With pay-as-bid pricing, the bidder's incentive is to bid as close to the clearing price as possible. Indeed, the pay-as-bid auction may be renamed "Guess the Clearing Price." The pay-as-bid auction rewards those that can best guess the clearing price. Typically, this favors larger companies that can spend more on forecasting, and are more likely to set the clearing price as a result of their size. In sharp contrast, uniform pricing favors the smaller companies (or those with small unhedged positions going into the market). With uniform pricing, the big suppliers make room for the smaller rivals. The small suppliers are able to free-ride on the exercise of market power by the large suppliers. Thus, the exercise of market power with pay-as-bid pricing, because it favors larger bidders, will tend to encourage consolidation and discourage entry; whereas the exercise of market power with uniform pricing encourages entry and reduces concentration. As a result, the market may evolve to more competitive structures under uniform pricing. This self-correcting feature of uniform pricing is especially valuable in markets like electricity that are repeated regularly.

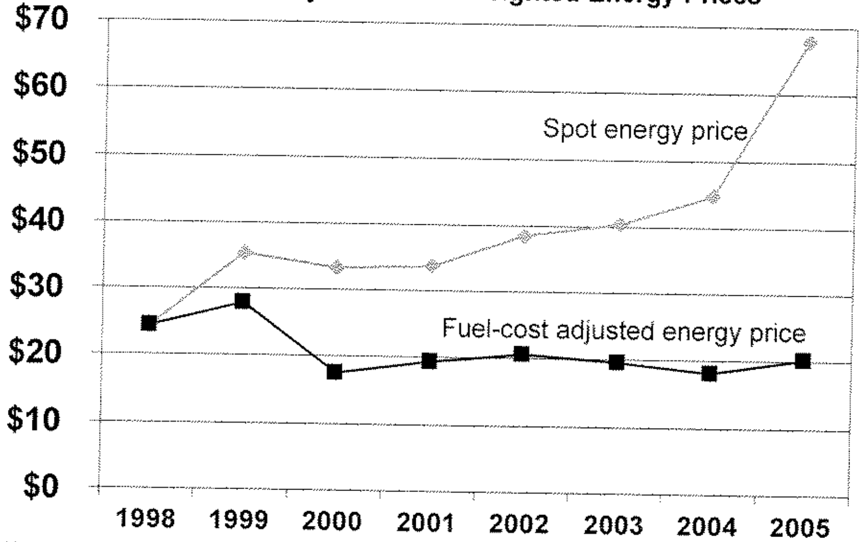
A final nail can be driven in the coffin of pay-as-bid optimism by considering the long run. Suppose the clearing price was so hard to guess that baseload plants guessed 20% lower than the actual clearing price on average in order to avoid missing a sale. They would earn less profit relative to other plants than under a uniform-price auction—just as hoped for by pay-as-bid advocates. Would that save consumers money? For a few years, it would, but no new baseload plant would be built until their profits returned to normal. This would only happen when a sufficient shortage of baseload plants had developed. That shortage would raise clearing prices in some hours when baseload is on or near the margin. This would just compensate for the 20% discount. As a consequence all plants would then be paid the same (their fixed plus variable costs), but the mix of plants would be inefficiently tilted away from baseload plants, because pay-as-bid would have discriminated against them. Consequently the average cost of producing electricity would increase. In other words, after a few years, even if pay-as-bid did work as hoped, consumers would still end up paying more.

Why energy prices are rising and what to do about it

We now return to the six factors responsible for rising electricity prices and provide some perspective. The first, and by far the largest factor, is simply the change in fuel costs, and in particular but not exclusively gas prices, over the last five years. This would increase electricity prices under any regime. The evidence that increases in fuel prices has been a major cause of increases in energy prices is compelling.

In PJM, the largest of the electricity markets, once we adjust for fuel cost, the spot energy price, which began at about $25/MWh, fell to about $20/MWh, and has remained there for the last six years, as shown below. However, the particular form of adjustment used in the graph assumes the law of one price and a complete lack of forward contracting. It demonstrates that some combination of market power reductions and efficiency gains have improved the market's performance, possibly in conjunction with some price suppression.[7] It also shows that, within a competitive spot market framework, fuel price increases are the entire cause of the price increase.

PJM Market Results 1998-2005
Comparison of Load Weighted Energy Prices to
Fuel-cost Adjusted Load Weighted Energy Prices



Note: Fuel-cost adjustment based on 1998 reference period and hourly marginal fuel type. All years are power years from April 1 to March 31, except 2005, which is through January 31. Source: PJM.

The second factor is the removal of retail rate caps. Some consumers have been temporarily protected from higher prices by retail rate caps. Naturally, when these caps are lifted, consumers experience rate shock. Even without such caps, consumers would have experienced a more gradual but more prolonged increase in prices. The only possible remedy for this problem is a shift from gas-fired generation to baseload generation, and, as described above, the market provides strong incentives for this shift.

The third factor is the shift to a disequilibrium in which, because baseload plants have a new-found advantage over gas-fired generation, they are in short supply. Being in short supply means they cannot set the price often enough, and instead, expensive gas plants set the price.

To investigate the impact of this factor, the graph above needs to be augmented with a comparison of wholesale energy prices and total fuel costs. This would allow an estimate of the extent to which disequilibrium in the stock of installed capacity has contributed to the windfall gains of baseload plants and the windfall losses of consumers. Such calculations would help focus attention on the need for better forward contracting.

The remedy for disequilibrium, as just noted, is more baseload capacity. This will take gas off the margin during some shoulder hours and lower the average price. When there are enough baseload units, they will no longer earn any windfall profits in the spot market.

An important question is whether there are barriers that will prevent the market from returning to equilibrium in this way. That is well beyond the scope of this paper, but it is important to note that the magnitude of the windfall consumer loss is closely tied to the size of such barriers. If the barriers are large, the problem could persist for many years; if they are low it might correct itself in only a few years. This report is not meant to suggest the barriers are large or difficult to remove; in fact they may be minimal or easily eliminated. The point is simply that to the extent they are allowed to exist, they will tend to cause windfall profits for existing baseload units.

The fourth factor, insufficient long-term forward contracting, is crucial. If complete long-term contracts were in place the disequilibrium problem would vanish. Unfortunately, forward contracting will not fix the problem after the fact. Once your house is on fire, fire insurance covering that fire is very expensive. California's experience with long-term contracts, during and after its electricity crisis beginning in 2000 is another vivid example.

An investigation of the extent of forward contracting would show that the consumers have not, in fact, experienced the entire cost increase implied by the spot price increases shown in the above graph. If an estimate of this effect could be made it would illustrate the benefits of forward contracting.

To protect against unexpected price increases, the forward contract must be signed while the increase is still unexpected. This does not mean it is too late to increase forward contract coverage. Rather it means that long-term forward contracts should be acquired by load in a way consistent with risk management and investment principles. Too often, load's contracting strategy appears to mimic that of the stock investor who looks only at past returns and buys yesterday's winners. The result is an outcome much worse than random purchase. Unfortunately, sound contracting by load has been frustrated by the absence of a well-defined representative of load to sign sensible long-term contracts. This is another basic problem that is beyond the scope of this paper.

Even if forward contracting is executed according to the best risk-management principles, it must be remembered that it will not, on average reduce expenditures—only the variance in those expenditures. The present disequilibrium does not represent a bias in the market. Had fuel costs shifted in the other direction the tables would have been turned. Similarly, forward contracting will increase consumer costs as often as it decreases them. Its benefit is to reduce risk—to counteract the spot market fluctuations by canceling both unexpected losses and unexpected gains.

The fifth factor is the law of one price. Under any market design, if the price of a MWh is high, a baseload plants will manage to get that high price, even if its costs are low. The law of one price plays a crucial role. It is not a law of nature, but it is a law that all competitive markets follow. As long as the market design remains competitive, there is little that can be done about this. Efforts to introduce price discrimination may succeed in the short-run, but in the long-run investment incentives are damaged and consumer costs are increased.

The sixth factor is the uniform-price design of the spot market. This is thought to be important when the law of one price is not recognized. Then it is often presumed that simply changing to pay-as-bid will up-end the law of one price. Fortunately, it will not. Suppliers that now bid zero, knowing the clearing price will be well above their marginal cost, will stop bidding zero if they are paid as bid. They will instead bid as close as they dare to the clearing price. While it is possible this will have a tiny depressing effect on the spot price, the result of lower prices will be that a few investments in new capacity will be discouraged (perhaps even before the pay-as-bid rule takes effect), supply will tighten, and the average spot price will be exactly where it would be under the uniform-price rule. Moreover, the uncertainty caused by forcing suppliers to bid based on their estimates of other's bids, instead of on the basis of their own costs, will reduce the efficiency of the dispatch. The net result will be to increase cost to consumers.

Conclusion

Three recommendations emerge from our analysis.

1. Do not switch from uniform-pricing to pay-as-bid pricing in the energy spot market. Hopes of saving money through price discrimination are naïve. Such a switch likely will increase consumer costs.
2. Do not attempt a regulatory taking of windfall profits and a regulatory allowing of windfall losses. Even if such a strategy achieved some short-run cost relief, it would destroy investment incentives, and thus, in the long-run, destroy the market.
3. Do look for sensible ways to encourage long-term forward contracts that hedge fuel-price shifts. Long-term contracts are the only market mechanism available to address the present concern.

Recommendations 1 and 2 are easy to implement. Recommendation 3 is much more difficult to follow. It requires solving one of the most important practical problems in electricity markets today. In today's markets, it remains unclear who should sign long-term forward contracts on behalf of residential and other small consumers. It is easy to say that contracts should be signed that are consistent with sound risk-management and investment strategy, but it is hard to implement when there is no counter-party to the contract. Residential and other small consumers are not represented properly in the current market design. This fact, not the design of the spot market, is at the heart of the current challenges in today's electricity markets.

One solution adopted in some states, such as New Jersey and more recently Illinois, is to require the electricity distribution companies to purchase long-term forward contracts from suppliers for residential and other small consumers. These contracts are procured in a sensible way via a competitive annual auction in which n-year contracts are purchased each year to cover a $1/n$ share of load. For example, New Jersey procures 3-year contracts covering $1/3^{rd}$ of load each year. Of course, consumers could enjoy even greater insurance from fuel-price shifts with contracts of even longer-term, procured on a more frequent basis, but there are credit and other issues that limit the optimal contract length.

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[1] We would like to thank PJM Interconnection for funding. The views expressed are our own.

[2] We use the term uniform-price auction, since that is the term from the auction literature. In electricity circles, it is sometimes called a single-price auction, and in financial circles it is mistakenly called a Dutch auction. In two-sided markets, in which suppliers make offers and buyers make bids, it is sometimes called a double auction, or a uniform-price double auction.

[3] The revenue increase is only to the level needed for a peaker to break even, and although this is the required long-run level, there should be dip in ICAP revenues when there is competitive entry of new base-load units if those units are making windfall profits as assumed in Stage 2.

[4] See Cramton, Peter and Steven Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity," white paper for the California Electricity Oversight Board, March.

[5] See Borenstein, Severin, James Bushnell and Frank Wolak (2002), "Measuring Market Inefficiencies in California's Wholesale Electricity Industry," *American Economic Review*, 92:5, 1376-1405 for empirical evidence in electricity markets; Gjerstad, Steven and John Dickhaut (1998), "Price Formation in Double Auctions," *Games and Economic Behavior*, 22, 1-29 for experimental evidence; and Gresik, Thomas A. (1991), "The Efficiency of Linear Equilibria of Sealed-Bid Double Auctions," *Journal of Economic Theory*, 53, 173-184, Satterthwaite, Mark, A and Steven R. Williams (1989), "The Rate of Covergence to Efficiency in the Buyer's Bid Double Auction as the Market Becomes Large," *Review of Economic Studies*, 56, 477-498, Satterthwaite, Mark A. and Steven R. Williams (1989), "Bilateral Trade with the Sealed Bid k-Double Auction: Existence and Efficiency," *Journal of Economic Theory*, 48, 107-133, and Wilson, Robert (1985), "Incentive Efficiency of Double Auctions," *Econometrica*, 53, 1101-1116, and Wilson, Robert (1993), "Design of Efficient Trading Procedures," in D. Friedman and J. Rust (eds) *The Double Auction Market*, Reading, MA: Addison-Wesley for theoretical support.

[6] See Kahn, Alfred E., Peter Cramton, Robert H. Porter, and Richard D. Tabors (2001), "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" Blue Ribbon Panel Report, California Power Exchange; Kahn, Alfred E. , Peter Cramton, Robert H. Porter, and Richard D. Tabors (2001), "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *Electricity Journal*, 70-79, July.

[7] For example, see Wolfram, Catherine D. (2005), "The Efficiency of Electricity Generation in the U.S. After Restructuring," in James Griffin and Steve Puller, eds., *Electricity Deregulation: Choices and Challenges*, University of Chicago Press, on efficiency gains.

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"We're at the home of Jim and Mindy Marks, who are about to discover that their utility bill has gone sky-high. Let's watch."